STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7336

Petition of Central Vermont Public Service)
Corporation for Approval of an Alternate)
Regulation Plan Pursuant to 30 V.S.A. § 218d)

REBUTTAL TESTIMONY OF WITNESS
MARK NEWTON LOWRY
ON BEHALF OF
CENTRAL VERMONT PUBLIC SERVICE CORPORATION

June 23, 2008

In his testimony, Dr. Lowry evaluates the proposed Non Power Cost Cap of DPS witness Ron Behrns. His evidence includes original empirical research and precedents in support of a corrected Non Power Cost Cap for CVPS should the Board prefer such an approach. Dr. Lowry also appraises the Subcap index proposed by CVPS and determines that the CVPS proposal has been constructed in a manner that is consistent with revenue index theory and his independently derived empirical results for CVPS.

Dr. Lowry sponsors the following exhibits:

CVPS-Rebuttal-MNL-1	Resume of Mark Newton Lowry
CVPS-Rebuttal-MNL-2	Revenue Adjustment Mechanisms for CVPS

REBUTTAL TESTIMONY OF MARK NEWTON LOWRY

Q. Please state your name, current title, and identify by whom you are employed.

A. My name is Mark Newton Lowry and I am the Managing Partner in the Madison, WI office of Pacific Economics Group ("PEG"). PEG is an economic consulting firm that is active in the field of utility regulation. The input price and productivity research that is often used to design rate and revenue adjustment mechanisms is a company specialty. PEG personnel have more than forty person-years of statistical cost research experience.

Q. Please summarize your educational background and professional experience.

A. Over the years I've been involved in the design of many alternative rate plans ("ARPs"). My practice has extended abroad to Australia, Canada, England, Japan, and Latin America. I have testified on the design of escalation formulas and other ARP issues on more than twenty occasions. Venues for my testimony have included Alberta, British Columbia, California, Hawaii, Kentucky, Maine, Massachusetts, New York, Oklahoma, Ontario, and Quebec. My clients include, by preference, a mix of utilities and regulatory commissions.

Before joining PEG I worked for several years at Christensen Associates in Madison, first as a senior economist and later as a Vice President and director of that company's Regulatory Strategy practice. My career has also included work as an academic economist. I have been an Assistant Professor of Mineral Economics at the Pennsylvania State University and a visiting professor at the Ecole des Hautes Etudes Commerciales in Montreal. My academic research and teaching stressed the use of mathematical theory and statistics in industry analysis. I have been a referee for several scholarly journals and have an extensive record of professional publications and public appearances.

Regarding my education, I hold an undergraduate degree in Ibero-American Studies and a PhD in applied economics and from the University of Wisconsin-Madison. A copy of my resume is attached as Exhibit CVPS-Rebuttal-MNL-1.

Q. Are there any other exhibits that you wish to sponsor?

A. Yes. I am the sponsor of the Pacific Economics Group report entitled "Revenue Adjustment Mechanisms for CVPS". It was prepared under my direction and supervision, and is attached as Exhibit CVPS-Rebuttal-MNL-2.

Q. Have you previously testified before the Vermont Public Service Board?

A. No.

INTRODUCTION

Q. What is the purpose of your testimony?

A. Central Vermont Public Service Company ("CVPS" or "the Company") has in Docket No. 7336 proposed an Alternative Regulation Plan ("ARP") that, like others approved in Vermont, features caps on the Company's revenue requirement. A "Unicap" limits growth in the company's total revenue requirement. A "Subcap" limits growth in the company's customer care and administrative and general ("A&G?) expenses.

On May 30, Vermont Department of Public Service ("DPS") witness Ron Behrns filed testimony that proposed an alternative ARP that features a cap on "non-power cost". In the words of Mr. Behrns, this cap

> would be formulaically determined by using a lagging consumer price index, prospectively adjusted for the rate year (1) targeted productivity

changes and (2) any unusual base rate changes occasioned by known and measurable and used and useful net plant and other rate base additions.

The base level of non power cost would escalate by about 2.03% annually in 2009 and 2010. Allowances for an uptick in capital spending would increase the escalation in the cap to an average of 2.56% in these two years.

I comment in this testimony on the reasonableness of the cap proposed by the DPS and offer alternative approaches to capping non-power cost should the Board choose to pursue that approach. My testimony will also review the CVPS Subcap from the same perspectives that I critique the DPS proposal's consistency with index theory and empirical results specific to CVPS.

APPRAISAL OF THE DPS PRPOSAL

Q. Please summarize your conclusions on the DPS proposal as described by Mr. Behrns.

A. The DPS proposal for a Non Power Cost Cap is conceptually flawed, unsupported by solid evidence, and should not be approved. My objections to the proposal encompass four areas: (1) the starting base for the cap, (2) the productivity target, (3) the choice of an inflation measure, and (4) the lack of an output adjustment.

Design of Revenue Adjustment Mechanisms

Q. Before you discuss your six objections to the DPS proposal, please begin by enunciating some principles for the design of revenue adjustment mechanisms.

A. A revenue adjustment mechanism makes automatic adjustments to a utility's revenue requirement or some component thereof. It is desirable for the mechanism to reflect changes in input prices and other business conditions that affect cost but are beyond the utility's control.

Revenue adjustment mechanisms must be carefully designed if they are to satisfy the just and reasonable standard under Vermont statute. The need for careful work is especially great in this proceeding since, under the CVPS proposal and that of the DPS, there is an unusual role for annual cost filings during the ARP period that is also found in the Green Mountain Power ("GMP") ARP. I will explain my concerns about this when I describe my specific objections to the DPS proposal.

Q. Granted that the escalation formula is a key part of the ARP, how do we ensure that the resulting customer rates are just and reasonable, as required by Vermont statute?

A. Index research using industry cost data is useful for designing revenue adjustment mechanisms that satisfy the just and reasonable standard of Vermont statute. The chief contribution of such research is to permit automatic adjustments for changes in business conditions that are beyond utility control but materially affect its cost. Index research has provided the basis for rate and revenue adjustment mechanisms that are currently operative in several nearby states and provinces. The list includes ARPs for Bay State Gas, Boston Gas, Central Maine Power, National Grid, NSTAR Electric and Gas, and the gas and electric power distributors of Ontario. Importantly, it appears as though statistical cost research provided some basis for the rate and revenue adjustment mechanism in the ARP that applies to Vermont Gas Systems (VGS). I discuss below how index research can be used to design a non power cost cap for CVPS.

A basic result of index theory is that the growth of cost equals input price inflation less productivity growth plus output growth. The relevant measures of output growth are those that drive cost growth. When the chief cost that is the focus of regulation is, as in this case, the cost of energy *distribution*, the number of customers served is a sensible measure of output growth. This reasoning provides the foundation for the following general formula for a revenue adjustment mechanism:

Growth Revenue = Inflation – X + growth Customers.

In this formula X, the "X factor", reflects a productivity growth target. One might also think of this as an efficiency savings target.

Q. Is there precedent for a revenue adjustment mechanism that features this kind of formula?

A. Yes. We have gathered some precedents for the design of revenue adjustment mechanisms in Table 1.

Table 1

Revenue Adjustment Mechanisms in Approved ARPs

Utility	Plan Approval Date	Application
Escalation Methodology		
Inflation, Productivity, & Customer Adjustments		
Southern California Gas	16-Jul-97	Gas utility base rate costs
Pacificorp (OR)	5-May-98	Electric distribution base rate costs
Consumers Gas (dba Enbridge Gas Distribution)	22-Apr-99	Gas utility base rate O&M expenses
Vermont Gas Systems	21-Sep-06	Gas utility base rate O&M expenses
Enbridge Gas Distribution	11-Feb-07	Gas utility base rate costs
Inflation Adjustments Only		
Pacific Gas & Electric	27-May-04	Electric utility base rate costs
		Gas utility base rate costs
San Diego Gas & Electric	17-Mar-05	Electric utility base rate costs
		Gas utility base rate costs
Southern California Gas	17-Mar-05	Gas utility base rate costs
All Forecast		
Southern California Edison	11-May-06	Electric utility base rate costs
Pacific Gas & Electric	15-Mar-07	Electric utility base rate costs
		Gas utility base rate costs
San Diego Gas & Electric[1]	Pending	Electric utility base rate costs
		Gas utility base rate costs
Southern California Gas[1]	Pending	Gas utility base rate costs
Orange & Rockland[1]	Pending	Electric utility base rate costs

Hybrid		
Pacific Gas & Electric	20-Dec-89	Gas & electric base rate O&M expenses
		Gas & electric base rate small plant additions[2]
Pacific Gas & Electric	16-Dec-92	Gas & electric base rate O&M expenses
		Gas & electric base rate all plant additions
San Diego Gas & Electric	3-Aug-94	Electric base rate O&M expenses
		Electric base rate small plant additions[2]
		Gas base rate O&M expenses
		Gas base rate small plant additions[2]
Southern California Edison	16-Jul-04	Electric base rate O&M expenses
		Electric base rate small plant additions[2]

[1]Settlement outcome

[2]Budgets for large plant additions established in separate proceedings

Note first that in 1999, the Ontario Energy Board approved a mechanism for escalating the allowed O&M expenses of Consumers Gas (dba Enbridge Gas Distribution), which serves Toronto. The formula was CPI – X + growth Output. The Board chose the number of customers served as the output measure most relevant to the cost of gas distribution.

When the number of customers is the output measure, revenue growth can be capped equivalently by the following general formula,

$$\text{Growth Revenue/Customer} = \text{Inflation} - X,$$

provided that the revenue requirement is also updated to reflect the *current* number of customers.

Q. Are there precedents for this kind of revenue per customer indexing?

A. Yes. This is effectively the approach that the Public Service Board approved for the operating expenses in the ARP of VGS. This approach has also been used to escalate the base rate revenue requirements of Enbridge Gas Distribution and Southern California Gas.

Q. Are there ways to simplify a formula based on index research while still preserving the reasonableness of the ARP?

A. Sometimes. One way to simplify the first general formula that I mentioned is to assume that the productivity factor (*i.e.*, the "X factor") is equal to growth in the number of customers served. The formula then becomes

$$\text{Growth Revenue} = \text{Inflation}.$$

This approach is used in the Subcap escalator that CVPS proposes and may be called the "inflation-only" method. The inflation-only method is a reasonable simplification when the appropriate X factor is "in the ballpark" of the rate of customer growth. Table 1 shows that this formula has been used recently to escalate the base rate revenue requirements of three utilities in the western United States.

Q. Are other approaches used in the design of revenue adjustment mechanisms?

A. Yes. One approach is the "all forecast" method. This essentially involves multiple forward test years in which both capital costs and O&M expenses are forecasted. With respect to CVPS, this approach would permit the company to correct for any failure of the current base costs to provide it with reasonable compensation. CVPS is currently preparing a multiyear cost forecast that could be used for this purpose. There is also a "hybrid" approach to the design of revenue adjustment mechanisms in which O&M budgets are established using indexing and capital budgets are based on forecasts.

Q. Where has the "all forecast approach" been used?

A. This approach has been used extensively in British regulation of energy utilities. In the United States, Table 1 shows that it has recently been used to establish revenue adjustment mechanisms for Pacific Gas & Electric and Southern California Edison. Pending settlements for Orange and Rockland, San Diego Gas and Electric, and Southern California Gas also feature all-forecast mechanisms. Multiyear forecasts have also been used recently to establish *price* cap plans for utilities in New York and Connecticut.

Q. How does the growth rate of the revenue requirements using the all forecast method compare to that from the non power cost cap proposed by the DPS?

A. The average growth rate of the revenue requirement in the plans detailed in Table 1 is about 3.5%. This is well above the 2.03% growth rate in base non-power cost proposed by the DPS.

Q. Where has the hybrid approach to the design of revenue adjustment mechanisms been used?

A. This approach has been used in California and Australia. One advantage of the hybrid approach is that it confines the use of indexing to the realm of O&M expenses, thereby sidestepping the somewhat complicated issue of how to measure capital price and quantity growth. The hybrid approach has the added advantage of accommodating capital spending surges such as that in which CVPS is currently engaged.

<u>Starting Base for the Cap</u>

Q. Please discuss the first objection that you mentioned earlier concerning the starting base of cost in the non power cost cap proposed by the DPS.

A. The proposed base for the DPS cap calculations is the itemized *pro forma* non energy cost shown in the settlement MOU in Docket No. 7321. This cost of service reflects

2006 cost conditions, as adjusted for certain known and measurable changes in 2007 and 2008 business conditions. However, it does not reflect some of the most important changes in business conditions, such as input price and customer growth, which have placed upward pressure on utility cost since 2006.

Other legitimate costs have been incurred since 2006 which were excluded from the MOU budget due to limitations imposed by the known and measurable criteria for inclusion. These include new activities, such as increased storm restorations, efforts to improve reliability for remotely situated customers, and an uptick in replacement capital spending. While many of these initiatives were contemplated in 2007, the spending plans were not documented to the degree required to meet the known and measurable standard and thus were excluded from the *pro forma* cost of service.

The approach proposed by the DPS has the effect of creating a cost cap that, throughout the ARP, would continue to disallow legitimate costs that were not represented in the *pro forma* total due to regulatory lag and other reasons. The cap thus begins with a basis that does not reflect the company's current cost challenges and is too low.

Q. Vermont has for many years set rates on the basis of an historical test year, as adjusted for known and measurable changes. Why should it deviate from this practice in this proceeding?

A. One reason for doing so is that the financial attrition produced by such regulatory lag is more serious than in the past. A utility can live with a "stale" rate if growth in its unit cost (*i.e.* its cost per unit of output as measured by billing determinants such as kWh of sales) is close to zero so that it can, with a modest acceleration in productivity growth, cut costs sufficiently to make up for the loss and perhaps go a year or two without a rate case. In Vermont, however, as in much of the Northeast, input price growth has accelerated in recent years and growth in delivery volumes, which can produce revenue to help finance utility operations between rate cases, has been slowed by aggressive energy efficiency programs.

A second reason for a modified approach to setting the base revenue requirement is that the Company is embarking upon a multiyear rate plan. Rate cases will occasionally produce rates that are, with the benefit of hindsight, too low. Under the old system, a new filing could always be initiated to request higher rates but this would not be possible during the ARP term.

Still another reason for a modified approach is that the Company currently has a low credit rating that raises its cost of capital. Resetting the base to allow timely cost recovery would help the Company improve its credit rating. This in turn would benefit customers by lowering the cost of capital that is included in rates.

For all these reasons, it is reckless and unfair to use the MOU revenue requirement as a base for an ARP if it is known to be stale. Mr. Behrns seemingly acknowledges this reality as it pertains to *capital* spending since he is prepared to adjust the cost cap for known and measurable changes in such spending. He does not, however, propose corresponding relief in the O&M budget.

Q. How would you propose to remedy the problem of an incorrect base for the ARP?

A. A partial solution to the problem is for the PSB to adjust the MOU cost of service to reflect the input price inflation and customer growth that occurred in 2007 and 2008.

This remedy will not, however, fix the problem that the MOU revenue requirement is insufficient to compensate CVPS for other legitimate cost increases that have occurred since 2006. This problem is only partly mitigated in the DPS proposal by the adjustments for "unusual rate base changes occasioned by known and measurable and used and useful net plant and other rate base additions".

Other approaches exist for solving the base problem. One is to set the base O&M expenses at their higher 2007 level, as proposed by CVPS for Subcap costs. Alternatively, the use of a revenue adjustment mechanism could be postponed for a year pending resolution of a new cost filing by CVPS to establish 2009 rates. The rate year 2009 cost of service could then become the base cost for the adjustment mechanism to set rates beginning in 2010.

Productivity Target

Q. Let's turn to your second objection to the DPS proposal, regarding the productivity target. Please begin by providing an overview of the concept of productivity.

A. A productivity index is the ratio of an output quantity index to an input quantity index. It is used to measure the efficiency with which firms convert inputs to outputs. Measured over time, the indexes can be used to identify productivity trends.

The growth trend of such productivity indexes is the difference between the trends in the output and input quantity indexes. Productivity thus grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index. Productivity growth is characteristically volatile due to fluctuations in output and the uneven timing of expenditures. The volatility is often greater for individual companies than for a group of companies such as a regional industry.

The output (quantity) index of a firm or industry summarizes trends in one or more dimensions of the amount of work it performs. In designing an output index, the choice of output measures depends on how it is used. In the design of a *revenue* adjustment mechanism, the objective is to measure the impact of output growth on utility *cost.* When designing a price cap index, the objective is to measure the impact of output growth on *revenue.* The number of customers served is, as we have seen, a sensible output measure when designing cost caps for CVPS.

The input quantity index of an industry summarizes trends in the amounts of production inputs used. Growth in the usage of each input category considered separately is measured by a subindex. Capital, labor, and miscellaneous materials and services are the major classes of base rate inputs used by electric utilities.

Q. How did the DPS establish its productivity target?

A. The DPS proposal sets a target at one half of the recent inflation of a CPI. I believe that the CPI for all urban areas in the US (CPI^U) was used for this purpose. Having calculated recent CPI^U growth of 4.05%, this method produced a productivity target of 2.025%.

Q. What are your objections to this method?

A. There is no conceptual reason why the productivity growth of an electric utility should be half of the inflation in a broad consumer price index. Productivity growth is, for one thing, generally not tied to inflation growth. For example, it doesn't generally accelerate when inflation does. The CPI^U has, in any event, only recently grown at a pace as brisk as 4%. From 1996 to 2006, for example, it averaged 2.51% growth. A productivity target equal to half of this would be only 1.25%.

Q. Are there precedents that we can look to for guidance in choosing a productivity target for CVPS?

A. Yes. The average productivity target approved by regulators for energy utilities around the world in ARPs that we have gathered is a little less than 1%. In 2006, the Board approved a productivity factor of 0.39% for the cap on the base rate operating expenses of Vermont Gas Systems.

Q. Assuming that appropriate adjustments can be made to the base non power revenue requirement of CVPS, what does your research suggest is the right productivity target for the corresponding revenue escalation formula in the next three years?

A. In original work for this proceeding, PEG has calculated the recent long run growth trends in the productivity of power distributor base rate inputs for CVPS and samples of Northeast and U.S. power distributors. The operations covered comprise power distribution, customer care, and each company's administrative and general services and general plant costs. The sample period for this research was 1996-2006. Details of our index research are found in Exhibit CVPS-Rebuttal-MNL-2. We found that the productivity of the sampled Northeast distributors averaged 0.76% annual growth. The 0.91% average annual growth in the productivity of CVPS was a little above this and virtually the same as the 1.03% average annual growth in the productivity of the full U.S. sample.

Q. Which of these productivity trend measures do you propose for CVPS?

A. I propose the productivity trend of the Northeast sample.

Q. Earlier you mentioned that you had a concern about annual cost filings during the ARP period. Could you please explain your concerns?

A. Under the CVPS and DPS proposal, CVPS would continue to make annual cost filings and the revenue requirement would be set at the lesser of the cap generated by the revenue escalation formula or the Company's actual cost. This requirement is, however, asymmetric. It can negatively affect the Company's earnings under the ARP but never enhance them. Over the long term, it is hard to see how this requirement meets the ARP statutory test of establishing a reasonably balanced system of risks and rewards that encourages the company to operate as efficiently as possible using sound management practices. This approach to capping revenue growth is very different from that employed in other jurisdictions around the world. The common approach is for the revenue requirement to be established solely by the revenue adjustment mechanism. The utility loses money when its cost is above the revenue requirement but can also enhance earnings if its cost is below the revenue requirement.

The earnings sharing adjustment mechanism (ESAM) shares benefits of cost containment initiatives with customers during ARP years and mitigates the earnings consequences of a poorly designed plan. Annual cost filings reduce the potential regulatory cost savings from an ARP. Furthermore, the use of annual cost filings weakens the potential performance incentives of a 3-5 year rate plan substantially. CVPS will know that if it incurs the upfront cost and extra effort to achieve a cost of service that is consistently lower than the cap all benefits will flow through to customers before the ARP has even expired.

Q. Is this an area where consistency between GMP and CVPS is desirable when designing a plan for CVPS?

A. Perhaps in the early years of alternative regulation implementation in Vermont, the annual cost filings can provide regulators with the additional assurance that rate adjustments under ARPs are just and reasonable. However, there is a downside to the annual cost filing requirement that should be recognized. For the reasons I just discussed, the annual cost filing requirement should be dropped as a requirement when the Company's plan is renewed. While such a requirement may be acceptable during the first phase of implementation of the Vermont alternative regulation statute, I believe that continuation of the annual cost filing requirement will undermine the long-term goals of the statute with respect to establishing clear incentives and a balanced system of risks and rewards.

Choice of Inflation Measure

Q. Now let's turn to your third objection to the DPS proposal, regarding the choice of the inflation measure. Mr. Behrns uses the CPI^U as the basis for his calculations. Is this a good measure of the input price inflation facing CVPS?

A. Generally not. As described further in the attached report, PEG has calculated a input price index for the base rate inputs used in power distributor services. Between 1996 and 2006 the CPI^U averaged 2.51% growth whereas the input price index for the for Northeast utilities averaged 3.07% growth. Thus, the inflation differential was (0.56%).

Q. Is this a surprising result?

A. No. We generally expect growth in the economy's *output* prices (*e.g.* those for consumer products) to be slower than the growth in its *input* prices by the amount of the economy's productivity growth. Likewise, CPI growth should generally be less than the input price growth for electric utilities.

Q. You mentioned earlier that the input price inflation facing CVPS has accelerated in recent years. Is there evidence of this in your research?

A. Yes. As shown in Figure 1, our input price index for CVPS averaged 3.81% growth from 2003 to 2006. From 1996 to 2003, this same index averaged only 2.78% growth. A 100 basis point swing materially affects the ability of a utility to live with the revenue requirement produced by the Vermont rate making process, which ignores recent inflation. A 100 basis point acceleration in productivity would be difficult for any utility to achieve, and the revenue requirement also fails to reflect customer growth, as we discuss further below.

Q. Where did Mr. Behrns obtain his 4.05% estimate of growth in the CPI^U?

A. The CPI^U grew by 2.9% in calendar 2007. Mr. Behrns is evidently referring to more recent inflation in the CPI^U. For example, for the first four months of 2008, the CPI^U has averaged a value 4.05% above its average for the same months of 2007. While 4% inflation may be a decent estimate of the current input price inflation facing CVPS, the CPI^U will typically underestimate that inflation.

Q. What then is the correct treatment of input price inflation in a revenue adjustment mechanism for CVPS?

A. One possible approach would be to fix the inflation allowance at a recent value, such as the 4% proposed by Mr. Behrns, which is similar to the recent trend in the input price index for CVPS. A sensible alternative is to use our CVPS input price index in the escalation formula. However, this formula is complicated and macro inflation measures like the CPI^U are familiar to the public and readily available from government agencies. If the Board chooses to use a CPI it should adjust the X factor to reflect the tendency of the CPI to grow more slowly than input prices. For example, X could be lowered by the 0.56% difference between Northeast utility input price and CPI^U growth from 1996 to 2006. Adjustments of this kind are common in index based regulation.

Q. Are there disadvantages to freezing the inflation rate?

A. Yes. A frozen inflation rate doesn't protect the company against the risk of hyperinflation, which is palpable given the current volatility of world commodity prices. By reducing utility operating risk, a flexible inflation rate makes it easier to extend the term of an ARP without violating the just and reasonable standard under Vermont law.

Lack of an Output Adjustment

Q. Your fourth objection to the DPS proposal pertains to the lack of an output adjustment. Please discuss the importance of an output growth adjustment.

A. I noted earlier that a general formula for revenue escalation that includes a productivity target will also typically include a term for customer growth. There are ample precedents for a customer growth term. A formula that does not include customer growth will also typically not have a productivity factor.

Q. How important is a customer growth adjustment to the finances of CVPS?

A. Witness Behrns makes several references in his testimony to the slow output growth of CVPS as limiting its need for revenue requirement escalation. But CVPS averages customer growth of around 1% annually. A failure to add a customer growth term to its revenue escalation formula would potentially short the company by around 100 basis points each year. This can be added to the typical 100 basis point burden from the failure to adjust rates for input price inflation.

Q. What of the DPS emphasis on the need for ARPs in Vermont to be consistent?

A. While consistency has some merits, Vermont has not been in the energy ARP "business" long enough that it has nothing to learn from revenue adjustment mechanisms in other jurisdictions. The failure to include a customer growth term in a revenue adjustment mechanism for CVPS would, in any event, be inconsistent with the mechanism approved for VGS. In my view, the VGS revenue escalation formula is more consistent with index logic and the accumulating precedents and is more worthy of emulation in this proceeding.

<u>Recommendations</u>

Q. Assuming that the Board chooses to adopt a non power cost cap for CVPS and makes suitable changes to the base cost using one of the methods you have mentioned, please summarize your views of an appropriate escalation formula for CVPS.

A. The cost that is subject to the cap should exclude the Company's VELCO earnings. The base revenue requirement should be adjusted from the MOU level to reflect input price and output growth through 2008 and an updated list of known and measurable changes in O&M expenses. The base should then be escalated by an index that properly reflects the net effects of input price, productivity, and output growth. This can be done through a mechanism with the general formula

Growth Revenue per Customer = Inflation – X.

like that in the VGS plan, but applied to a broader range of non-power costs

If a macroeconomic inflation measure like CPI^U is used in the formula, X should include a productivity target and an inflation differential. Our research suggests that the X factor should be 0.18% [which I calculate as 0.74 – (3.07-2.51)]. Based on our calculations, an index of this kind would have averaged 3.620% growth from 2001 to 2006 and 4.010% growth in the more recent 2003-2006 period. As a final step, cost would be allowed to grow by the additional basis points proposed by the DPS to finance the uptick for investments in AMI and replacement capital spending.

Q. Why should the Board adopt a revenue adjustment cap mechanism for CVPS that is based on the input price and productivity trends of power distributors when the Company's non power costs also include generation and subtransmission operations?

A. Power distributor operations (which include customer care) accounts for the lion's share of the Company's Vermont-jurisdictional non-energy cost. Subtransmission systems have economics similar to that of distribution systems (*e.g.* similar input price trends) and are, indeed, treated as distribution systems in the accounts of some U.S. utilities. Our proposal has, in any event, a far more scientific foundation than that of the DPS.

AN APPRAISAL OF THE CVPS SUBCAP PROPOSAL

Q. Please review the Subcap proposal presented by CVPS witness Deehan.

A. CVPS proposed that Subcap costs be escalated annually by the growth in the CPI for services.

Q. Is this consistent with the principles you have enunciated concerning the design of revenue adjustment mechanisms?

A. Yes. CVPS proposed a formula that allows Subcap costs to escalate annually by the growth in the national CPI for services. This approach is consistent with the principles we have enunciated for the design of revenue adjustment mechanisms. Customer care and A&G costs are the most labor intensive parts of a customer's business. Labor prices tend to rise more rapidly than the CPI. The CPI for services is a better match for the trend in the price of Subcap inputs because the Subcap covers consumer services that are comparatively labor intensive. Over the 2001-2006 sample period, our research revealed that the prices of inputs used in Subcap costs averaged 3.08% growth, while the CPI for services averaged 3.19% growth. The inflation differential resulting between the Subcap input price index and the CPI for services from 1996 to 2006 is thus only 0.11% (3.19 – 3.08). Given CVPS customer growth of 0.99% over this period, a Subcap escalation formula equal to growth in the CPI for services would have involved an implicit productivity target of 0.88 (computed as 0.99% customer growth less the 0.11% difference between CPI growth and Subcap input price growth). This is a little above the average productivity growth of the Northeast sample during this period and very similar to the trend achieved by CVPS. Subcap costs are therefore a candidate for an "inflation only" revenue adjustment mechanism.

Q. Has the Company proposed a reasonable base from which to move its Subcap forward in time during its Plan?

A. The Company proposed the use of actual expenditures incurred in 2007 as the base for the Subcap index. By beginning with an actual cost basis and escalating that value with actual inflation during the intervening years, the issues related to a stale cost base are avoided and the updated base will prevent the index from capping revenues in future years at an unjustly low level.

Q. Does this conclude your testimony?

A. Yes it does.

Figure 1